Queue Cluster 9 Phase II Report

November 22, 2017

This study has been completed in coordination with Southern California Edison per ISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP)
<table>
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<tr>
<th>No.</th>
<th>Date</th>
<th>Document Title</th>
<th>Description of Document</th>
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<tr>
<td>3</td>
<td>11/22/2017</td>
<td>Queue Cluster 9 Phase II Appendix A Report</td>
<td>Final Phase II Interconnection Study Report</td>
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<tr>
<td>2</td>
<td>02/28/2017</td>
<td>Addendum #1 to Queue Cluster 9 Phase I Appendix A Final Report</td>
<td>The purpose of this report is to publish the written comments provided by the IC to SCE in accordance with the timelines stated per Section 4.5.7 in GIP</td>
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<td>01/18/2017</td>
<td>Queue Cluster 9 Phase I Appendix A Final Report</td>
<td>Report to disclose results of the Queue Cluster 9 Phase I study</td>
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A. INTRODUCTION

The Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to Southern California Edison (SCE) for its proposed Project. The Project requested a Point of Interconnection (POI) at SCE’s Bolsa 66 kV Switchrack, located in Orange County, CA, and delivery to the ISO Controlled Grid at SCE’s Barre 220 kV Substation. The Project consists of the Generating Facility and the IC’s Interconnection Facilities as illustrated below in Figure A.1. A map that illustrates the location of the Project is provided below in Figure A.2. Moreover, the Project information is summarized in Table A.1.

In accordance with FERC approved SCE’s WDAT Attachment I Generator Interconnection Procedures (GIP), the Project was grouped with Queue Cluster 9 (QC9) Phase II projects to determine the impacts of the group as well as impacts of the Project on the ISO Grid.

An Area Report and, where applicable, a Subtransmission Assessment Report, have been prepared separately identifying the combined impacts of all projects on the ISO Grid and to distribution facilities served out of the Barre 66 kV Subtransmission System, respectively. This Appendix A report focuses only on the impacts or impact contributions of the Project at the local distribution system, and is not intended to supersede any contractual terms or conditions specified in the GIA.

The report provides the following:

1. Distribution system impacts caused by the Project.
2. System reinforcements necessary to mitigate the adverse impacts caused by the Project under various system conditions.
3. A list of required facilities and a good faith estimate of the Project’s cost responsibility and time to construct these facilities. Such information is provided in Attachment 1 and Attachment 2 as separate documents in the Appendix A Project report package.

The Project encompasses energy storage equipment that triggered the need to analyze its charging impacts to the Distribution Provider’s (SCE) electric system. The analyses focused on the charging demand aspects of the Project and considered varying levels of system demand with minimal generation dispatch within the local distribution system.

Consequently, the report also discloses the adequacy of SCE’s Electric System to support the Project when operating in charging mode, identifies system limitations that may restrict the Project when operating in charging mode during certain demand conditions, and provides a high-level explanation of potential exposure to the Project and charging restrictions on the electric system. The Generating Facility will follow ISO market dispatch instructions when in charging demand mode and in discharging mode.

All equipment and facilities comprising the Interconnection Customer’s 204.6 net MW (204.6 gross MVA Hybrid Solar Photovoltaic and Energy Storage Generating Facility in Huntington Beach, California, as disclosed by the Interconnection Customer in its Interconnection Request, as may have

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3 It should be noted that construction is only part of the duration of months specified in the study, which includes detailed engineering, licensing, and other activities required to bring such facilities into service. These durations are from the execution of the GIA, receipt of all required information, funding, and written authorization to proceed with design and engineering, procurement, and construction from the IC as will be specified in the GIA to commence the work.

4 Charging is defined as when the Project draws energy from the grid to “charge” the Project-associated charging facility.
been amended during the Interconnection Study process, which consists of (i) [redacted] with a rated output of [redacted] each for a combined gross output of 102.6 MW and [redacted] with a rated output of 0.5 MW each for a combined gross rated output of 102 MW as measured at the inverter's terminals, (ii) the associated infrastructure, (iii) meters and metering equipment, and (iv) appurtenant equipment. The [redacted] shall consist of the Generating Facility and the Interconnection Customer's Interconnection Facilities.

Since the Generating Facility has the capability of producing and delivering more MW at the Point of Interconnection than the requested amount of 100.0 MW, the Interconnection Customer will need to install or demonstrate that a control system will be put in place which will manage the Generating Facility output to not exceed 100.13 MW (net) as measured at the high side of the main transformer bank in order to ensure the project does not exceed the maximum requested 100.0 MW Point of Interconnection delivery amount, which takes into account the expected losses on the generation tie line. The [redacted] shall consist of the Generating Facility and the Interconnection Customer's Interconnection Facilities, and is shown in Figure A.1. The internal project losses corresponding to the Generating Facility not exceeding the maximum requested 148.1 MW at the Point of Interconnection are provided in Tables 1 and 2 below.

\(^*\) MW (net) represents the MW value as measured on the high side of the main transformer bank to achieve the desired MW delivery at the POI.

\(^*\) MW (net) represents the MW value as measured on the high side of the main transformer bank.
Figure A.1: Project One-Line Diagram
<table>
<thead>
<tr>
<th><strong>Project Location</strong></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Distribution Provider’s Planning Area</strong></td>
<td>Distribution Provider’s Metro Area</td>
</tr>
<tr>
<td><strong>Interconnection Voltage</strong></td>
<td>66 kV</td>
</tr>
<tr>
<td><strong>Point of Interconnection</strong></td>
<td>Bolsa 66 kV Substation</td>
</tr>
<tr>
<td><strong>Number and Types of Generators (PV)</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Number and Types of Generators (BESS)</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Requested Maximum Project Delivery at Point of Interconnection</strong>&lt;sup&gt;a&lt;/sup&gt;</td>
<td>100 MW</td>
</tr>
<tr>
<td><strong>Generation Tie Line</strong></td>
<td>0.67 miles, 1272 kcmil &quot;Pheasant&quot;</td>
</tr>
<tr>
<td></td>
<td>Line Rating: 1187A / 1187A</td>
</tr>
<tr>
<td></td>
<td>$Z_1$(p.u.): 0.001261+j0.010035, $B = 0.00038$</td>
</tr>
<tr>
<td></td>
<td>$Z_2$(p.u.): 0.005045+j0.050174, $B = 0.00038$</td>
</tr>
<tr>
<td><strong>Main Step-Up Transformer(s)</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Main Transformer</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Collector Equivalent</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Pad-Mount Transformer(s)</strong></td>
<td></td>
</tr>
</tbody>
</table>

<sup>a</sup>The MW output at the Point of Interconnection varies under different operating conditions. The IC is reminded that this value is tied to the generation tie-line (gen-tie) losses. The estimated Maximum Net Output value at Point of Interconnection and gen-tie Losses illustrated above are contingent upon the accuracy of the technical data provided by the IC, and are subject to change should the IC change its gen-tie parameters during the detailed engineering and design phase of the Project. Please note that the Project shall not exceed the total net output of 100 MW at the Point of Interconnection.
Generator Auxiliary Load and/or Station Light and Power  |  2.0 MW
Voltage Regulation Devices                  |  None identified for this project
Dynamic Models Used                        |  PV
                                                |  regc_a, reec_b, repc_a, lhvrt, and lhfrt
                                                |  BESS
                                                |  regc_a, reec_b, repc_a, lhvrt, and lhfrt
Deliverability Requested                   |  Full Capacity
Option (A/B) Requested                     |  Option A

Proposed Dates

| In-Service Date (ISD)                  |  9/15/2019
| Initial Synchronization Date/Trial Operation |  9/30/2019
| Commercial Operation Date (COD)        |  12/31/2019

B. STUDY ASSUMPTIONS

For detailed assumptions regarding the group cluster analysis, please refer to the QC9 Phase II Area Report. Below are the assumptions specific to the Project:

1. The Project was modeled as described in Table A.1.
2. The facilities that will be installed by SCE and the IC are detailed in Attachment 1.
3. Roles and Responsibilities for Environmental Activities, Permits, and Licensing.

   The assumptions for the Environmental Activities, Permits, and Licensing are as follows:
   i. Internal Substation Scope:
      - SCE will perform all environmental studies and monitoring of all SCE internal substation construction activities.
   ii. 66kV Generation Tie Line Scope:
      - SCE’s scope of work will not require a California Public Utilities Commission (CPUC) license.
      - SCE will act as the environmental liaison between the SCE team and IC team, and the lead for regulatory agency communication.
        o Collaborate with the IC during the environmental study phase on proposed study methodologies and findings, as studies are being planned and performed for SCE’s scope of work.
        o Review IC’s California Environmental Quality Act (CEQA) and National Environmental Policy Act (NEPA) documents, technical studies, surveys, and other environmental documentation addressing SCE’s scope of work (IC to include SCE’s scope of work in their environmental document).
        o Review of internal Environmental Services (ES) existing technical documents when available
        o Regulatory agency communication, consultation, and reporting

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4 Such dates are specified in the Project’s Attachment B. Actual ISD and COD will depend on licensing, engineering, detailed design, and construction requirements to interconnect the Project.
• Permit acquisition
  • Support SCE team in developing the project description, including scope changes during permitting/pre-construction or construction.
  • Communicate scope changes to the IC's environmental team, discuss/approve subsequent actions including new surveys as necessary
  • Prepare environmental requirements for construction clearance
  • Develop communication plan
  • Construction monitoring oversight
  • General Order 131-D Consistency Determination and Environmental Evaluation
  • Environmental Awareness/Worker Environmental Awareness Program [WEAP] training
  • Pre-construction coordination field visit
  • Construction and post-construction site assessments

- IC performs all environmental studies and prepares draft environmental permit applications related to the installation of SCE's Interconnection Facilities, Distribution Upgrades, and Network Upgrades. The IC's responsibilities include, but are not limited to notifications to the Native American Heritage Commission (NAHC) and follow-up notifications to the tribes and individuals in the NAHC contact list, performing cultural and paleontological resources records searches, performing cultural resources inventories (survey and recording), performing testing and evaluation and/or data recovery of archaeological sites as applicable, and providing the appropriate documentation in the form of inventory reports, research design and/or data recovery reports as applicable, cultural and paleontological monitoring when/if required, and arranging curation agreements for artifacts and fossil specimens collected, performing a California Natural Diversity Database search, performing a habitat assessment, performing protocol or focused surveys for species with the potential of occurring in identified suitable habitat, conducting jurisdictional delineations for wetlands or other regulated waters, preparing draft environmental permit applications, performing pre-construction biological resource surveys, performing biological resource monitoring during construction, performing cultural and paleontological monitoring during construction, mitigation costs including, but not limited to, offsite/compensatory mitigation and onsite restoration, and developing mitigation plans or other environmental reports or submittals, if required, to support installation of SCE’s Interconnection Facilities, Distribution Upgrades, and Network Upgrades.

- Prior to commencing work and during execution of work, the IC must collaborate and obtain ES concurrence on all work outlined above. Should the IC-performed environmental studies, surveys, or monitoring not meet the Federal or State industry standards in accordance with Applicable Laws and Regulations, and as determined by ES, the IC shall be obligated to remedy deficiencies under SCE/ES’s direction, or ES shall undertake additional environmental studies, surveys, or monitoring at the sole expense of the IC. If these scenarios occur, the cost estimate must be updated to reflect the changes to the assumptions.

4. Charging Facility Considerations:
  • The Project encompasses energy storage facilities. The details pertaining to the Reliability Study for the Generating Facility when operating in charging mode are included in this Appendix A report.
• SCE’s distribution standards and practices are in the process of being updated to address energy storage facilities. The proposed Plan of Service in this report may require changes to comply with the updated distribution design standards and practices.
• This study assumes that the IC’s facility will include all equipment, software, appropriate controls, and other related equipment necessary to maintain the energy storage facility demand profile per SCE requirements.
• Upon execution of the GIA, SCE will provide the IC with the required ramp rate control parameters. The ramp rate controls will be a function of the demand on the distribution system, as well as SCE’s Electric System configuration (additional parameters may be considered, as necessary).
• In order to ensure limits are communicated in a timely and reliable manner, the IC is responsible for providing reliable communications between the Project and SCE’s System to transmit the required telemetry data as outlined in the Distribution Provider’s Interconnection Handbook. Should the communication channel fail, the Project’s operating limits will automatically revert to zero (no charging allowed).
• If the Project does not follow the given charging limitations, the Project will be disconnected.
• The Project will need to participate in the Distributed Energy Resource Management System (DERMS).
• The Distributed Energy Resource Management System (DERMS), which at this stage is a technical concept, is under development to incorporate the increased amount of energy storage applications to SCE’s Electric System with minimal distribution upgrades. DERMS will actively communicate allowable Project limits under charging mode to maintain safe and reliable operation of the distribution system. The energy storage component of the Project will need to be metered separately from the revenue load components. The IC should be prepared to install multiple sets of metering (i.e. separate sets of PTs & CTs and supporting metering equipment) for the Project. Additionally, the Project may also need to connect the energy storage component to a dedicated transformer, this will be determined at a later date.

5. Other Items to Consider:
• The Project is dependent upon the installation of the Distributed Energy Resource Management System (DERMS). Should DERMS not be operational prior to this Project initializing commercial operation, this Project may elect to: (i) follow a static charging restriction schedule provided by SCE until DERMS is operational, or (ii) wait for DERMS to be completed.
• Final metering requirements will be identified as part of project execution and could result in modifications to the Project.
• Short-Circuit Duty Considerations: SCD operational mitigation was identified taking into account new generation projects that have executed GIAs, approved Transmission Network Upgrades fully permitted and under construction, and new generation projects including the QC9 Phase II projects, which do not yet have an executed GIA. The study results for these

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5 It is assumed that ramp rates for each energy storage facility will be dependent upon their inherent technology types. While very quick response ramp rates (i.e. going from full charge to full discharge instantaneously or vice-versa) may be beneficial for other grid services, the Distribution Provider may, at its discretion, require establishing limits to maintain safety and reliability of its distribution system.
operational studies are provided in Section II of the Generation Sequencing Implementation Short Circuit Duty evaluation (Appendix G). Based on the study results, replacement of four (4) Vincent 500 kV circuit breakers (triggered by QC3&4) are required to be in place in order to enable interconnection of the Project. Replacement of the four (4) Vincent 500 kV circuit breakers has not been initiated, because this upgrade is required only when sufficient generation projects (with executed GIAs in good standing) achieve ISD. The identification of the need for the Vincent 500 kV circuit breaker upgrades is based on the assumption that all queued generation projects actually materialize and are interconnected, but the true need occurs only when sufficient queued generation achieves ISD. This SCD mitigation will be continuously evaluated as part of ongoing GIA negotiations with queued generation projects to properly define the actual trigger of SCD mitigation based on the actual execution of GIAs and development of generation facilities toward commercial operation.

C. TECHNICAL REQUIREMENTS

1. Preliminary Protection Requirements
   Protection requirements are designed and intended to protect SCE’s Electric System only. The preliminary protection requirements were based upon the interconnection plan as shown in the one-line diagram depicted in line item #4 in Attachment 1.

   The IC is responsible for the protection of its own system and equipment and must meet the requirements in the Distribution Provider’s Interconnection Handbook.

2. Power Factor Requirements
   The Generating Facility will be required to maintain a composite power delivery at continuous rated power output at the high-side of the generator substation at a power factor within the range of 0.95 leading to 0.95 lagging.

3. Operating Voltage Requirements
   Under real-time operations, the project will be required to operate under the control of automatic voltage regulator with settings as shown in the figure below. The actual values of the Vmin and Vmax will be provided once the project executes a Generation Interconnection Agreement and detailed engineering and design is complete. The Vmin and Vmax values are to be used as the basis for setting up the automatic voltage control mode (with its automatic voltage regulator in service and controlling voltage) of the Generating Facility in order to maintain scheduled voltage at a reference point.

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6The IC is advised that there may be technical requirements in addition to those that outlined above in Section C of this report that are included in the Interconnection Handbook or that will be addressed in the Project’s GIA.
4. Harmonic Requirements
The harmonic impact of the subject inverter-based generation was not part of this study. Impacts on voltage distortion levels may be significant due to the penetration level of the generation facility with respect to the local distribution grid strength. As with all equipment connected to the SCE Electric System, the generation project will be subject to the provisions of CPUC Rule 2.E, allowing SCE to require the IC to mitigate interference with service to other SCE customers, including harmonic impacts, if the harmonic interference is caused by the IC.

5. Low/High Voltage Ride-Through (LHVRT) and Low/High Frequency Ride-Through (LHFRT) Capability
Actual fault events have demonstrated that certain synchronous generators (i.e., inverters) from specific manufacturers may be susceptible to false tripping or temporary shutdown during fault conditions. The most severe disturbance to date resulted in the temporary loss of 1,178 MW at photovoltaic plants when inverter control systems throughout Southern California responded to a 500 kV fault by temporarily stopping the production of electric power. Based on the results of an investigation performed into this issue, several causes and contributing factors have been identified which include:

a. Apparent miscalculated frequency at many inverters when fault-induced phase shifts occurred in the reference voltage
b. Inverter protection settings set to meet IEEE 1547 standards
c. Momentary overvoltage
d. Momentary under-voltage
The NERC PRC-024-2 standard currently allows generators to trip if the system conditions are outside of a defined set of bounds. Because different inverter manufacturers use different methods to calculate frequency (zero crossing, DFT, PLL, etc.), the methods used by some manufacturers have resulted in calculations of the instantaneous frequency during power system disturbances that do not accurately reflect actual frequency. Inaccurate frequency calculations may result in the reduction of electric power from inverter-based resources which is an unacceptable response. In addition, voltage transients caused by capacitive switching (among other potential causes) can cause inverters to trip due to a momentary overvoltage condition which too is an unacceptable response unless the Project has reached the power factor lead (buck) limits and the voltage is still in excess of the maximum allowable voltage limit for a duration longer than the no trip timer defined in PRC-024-2.

When under-voltage occurs during the fault, some inverters may cease operation temporarily. Such performance may not be allowed in the future reliability standards/interconnection standards.

The IC should work with the inverter manufacturer to ensure these three issues are properly addressed. Dynamic simulation study results illustrating the frequency and voltage performance of the Project based on the technical parameters supplied for the Project are provided as part of the study results. The results will evaluate performance to ensure that the Project remains online during voltage disturbances up to the time periods and corresponding maximum allowable voltage levels set forth in NERC PRC-024-2 and producing power immediately following fault disturbance clearing at the levels prior to the disturbance.

6. Environmental Activities, Permits, and Licensing
   Please see Appendix K of the Area Report.

D. RELIABILITY STANDARDS, STUDY CRITERIA AND METHODOLOGY

The generator interconnection studies were conducted to ensure the ISO Controlled Grid is in compliance with the North American Electric Reliability Corporation (NERC) reliability standards, WECC regional criteria, and the ISO planning standards. Refer to Section C of the Area Report for details of the applicable reliability standards, study criteria, and methodology.

E. POWER FLOW RELIABILITY ASSESSMENT RESULTS

Discharging Analysis of the Project

Steady State Power Flow Analysis Results

1. Thermal Overloads
   The group and/or subtransmission study indicated that the Project does not contribute to overloads to any facility under Base Case or Single Contingency scenarios. Consequently, the Project is not allocated cost for any Distribution Upgrades identified to address power flow issues. The details of the analysis are provided in the Barre 66 kV Subtransmission Assessment. The results identified in this section assume QC9 Phase II Projects dispatched at their requested maximum output.
2. **Power Flow Non-Convergence**
   There were no non-convergence issues identified with the inclusion of the Project operating at the required power factor range, refer to Area Report for additional details.

   While the project is not responsible for non-convergence issues in the Barre Subtransmission System, the Power Flow Analysis found that loss of the Barre 4A 220/66 kV Transformer Bank would result in loss of service to everyone connected on the Barre C Section. Operator action during such an event includes but is not limited to closure of the Barre sectionalizing circuit breakers to restore service to the Barre 66 kV C-Section.

3. **Voltage Performance**
   There were no voltage performance issues identified with the inclusion of the Project, refer to Area Report for additional details.

4. **Power Factor Evaluation**
   FERC Order 827 provides the reactive power requirements for newly interconnecting non-synchronous generators which requires these resources to design the facility to be capable of providing reactive power to meet power factor 0.95 as measured on the high-side of the main transformer.

   Base case power flow was evaluated to determine reactive power losses internal to the Project in order to ascertain if the reactive capability of the Project are adequate to supply these losses and meet the power factor requirements. A summary of the power factor evaluation is provided in the tables below.

<table>
<thead>
<tr>
<th>Reactive Power Requirements (BESS)</th>
<th></th>
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<tbody>
<tr>
<td>Pad-mount transformer losses</td>
<td>5.19 MVARs</td>
</tr>
<tr>
<td>Main transformer losses</td>
<td>12.33 MVARs</td>
</tr>
<tr>
<td>Auxiliary Load requirements</td>
<td>0.484 MVARs</td>
</tr>
<tr>
<td>PF requirements at High Side of Transformer</td>
<td>32.97 MVARs</td>
</tr>
<tr>
<td><strong>Total VAR Requirements</strong></td>
<td>50.97 MVARs</td>
</tr>
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<table>
<thead>
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<th>Reactive Power Supply</th>
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<tbody>
<tr>
<td>SMA Sunny Central Power Inverters</td>
<td>45.9 MVARs</td>
</tr>
<tr>
<td>Collector System</td>
<td>0.04 MVARs</td>
</tr>
<tr>
<td><strong>Total VAR Supply</strong></td>
<td>45.9 MVARs</td>
</tr>
<tr>
<td>Reactive Power (Shortage) / Surplus Total Requirements less Total Supply</td>
<td>(5.1) MVARs</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Reactive Power Requirements (PV)</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Pad-mount transformer losses</td>
<td>5.23 MVARs</td>
</tr>
<tr>
<td>Main transformer losses</td>
<td>12.38 MVARs</td>
</tr>
<tr>
<td>Auxiliary Load requirements</td>
<td>0.48 MVARs</td>
</tr>
<tr>
<td>PF requirements at High Side of Transformer</td>
<td>32.97 MVARs</td>
</tr>
<tr>
<td><strong>Total VAR Requirements</strong></td>
<td>51.06 MVARs</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Reactive Power Supply</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>TMEIC Solar Ware Samurai Power Inverters</td>
<td>45.9 MVARs</td>
</tr>
<tr>
<td>Collector System</td>
<td>0.87 MVARs</td>
</tr>
<tr>
<td><strong>Total VAR Supply</strong></td>
<td>46.8 MVARs</td>
</tr>
</tbody>
</table>
Based on the technical details provided, the Project, as proposed, does not meet the 0.95 power factor requirement as measured at the high-side of the main transformer bank.

5. Required Mitigations

With the Project providing the required 0.95 leading/0.95 lagging power factor regulation capability at the high side of the generator substation. The Project will require anti-islanding protection for loss of the Barre 4A Transformer Bank and will not be allowed to operate under such an outage condition. Furthermore, the Project will not be allowed to operate under a condition following closure of the Barre 66 kV sectionalizing breakers.

Charging Analysis of the Project

Steady State Power Flow Analysis Results

1. Thermal Overloads

The group and/or subtransmission study indicated that the Project contributes to overloads on the following facilities listed below under normal and single contingency conditions. The details of the analysis and overload levels as well as the details of the recommended mitigation to address these overloads are provided in the corresponding Metro Area and Barre 66 kV Subtransmission Assessment Reports. Furthermore, the power flow analysis found that loss of the Barre 4A 220/66 kV Transformer Bank would result in loss of service everyone connected on the Barre C Section.

I. Normal Conditions

- Barre 4A 220/66 kV Transformer Bank
- Apollo-Bolsa-Team 66 kV Subtransmission Line
- Bolsa-Oceanview-Trask 66 kV Subtransmission line

II. Single Contingency

- Bolsa-Oceanview-Trask 66 kV Subtransmission Line overloads under loss of the Apollo-Bolsa-Team 66 kV Subtransmission Line
- Apollo-Bolsa-Team 66 kV Subtransmission Line overloads under loss of the Bolsa-Oceanview-Trask 66 kV Subtransmission Line

The Study identified single contingency overload under loss of Barre 1A and 3A and closure of the sectionalizing breakers. This operating condition can result in overloading the remaining A-Banks in excess of their long-term emergency rating. Further details can be found in the Barre 66 kV Subtransmission Assessment Report.

2. Power Flow Non-Convergence

There is an identified non-convergence issue following loss of the Barre 4A Transformer Bank. Loss of the Barre 4A Transformer Bank would result in loss of service to everyone connected on the Barre C Section.
The Project will require anti-islanding protection for loss of the Barre 4A Transformer Bank and will not be allowed to operate under such an outage condition. Furthermore, the Project will not be allowed to operate under a condition following closure of the Barre 66 kV sectionalizing breakers.

3. Voltage Performance
   There were no voltage performance issues identified with the inclusion of the Project, refer to Area Report for additional details.

4. Required Mitigations
   Per the WDAT, the Project is required to provide 0.95 leading/0.95 lagging power factor regulation capability at the high side of the main transformer bank, in addition to the following Distribution Upgrade(s) (DUs) to mitigate the power flow impacts of the Project described above under Voltage Performance.

   a. DERMS
      The Project will need to be added to DERMS. DERMS is a management based software that will specify the available charging capacity for the Project based on the real time loading information for the following items that require monitoring and assist in upholding applicable charging restrictions:

      1. Monitor the Barre 4A 220/66 kV Transformer Bank
      2. Monitor the Bolsa-Oceanview-Trask 66 kV Line
      3. Monitor the Apollo-Bolsa-Team 66 kV Line

      Refer to Attachment 1 and Attachment 2 for scope description and associated cost responsibility of these Distribution Upgrade(s).

F. TRANSIENT STABILITY EVALUATION

1. Project Performance
   Dynamic simulation study results illustrating the frequency and voltage performance of the Project based on the technical parameters supplied for the Project are provided below.
Voltage plot for Generating Facility at high side of main transformer bank with fault at the Point of Interconnection

Frequency plot for Generating Facility at high side of main transformer bank with fault at the Point of Interconnection
The results indicate acceptable project performance and reflects the expected performance when Project ultimately interconnects.
2. **System Performance**

System transient stability performance was found to be acceptable. Refer to the Area Report, for additional details pertaining to the Phase II transient stability evaluation criteria and assessment results, respectively.

**G. SHORT-CIRCUIT DUTY RESULTS**

Short-circuit studies were performed to determine the fault duty impact of adding the Phase II projects to SCE’s Electric System and to ensure system coordination. The fault duties were calculated with and without the projects to identify any equipment overstress conditions. Once overstressed circuit breakers are identified, the fault current contribution from each individual project in Phase II is determined. Each project in the cluster will be responsible for its share of the upgrade cost based on the rules set forth in Section 4 of the GIP.

1. **Distribution Provider**

All bus locations where the Phase II projects increase the short-circuit duty by 0.1 kA or more and where duty was found to be in excess of 60% of the minimum breaker nameplate rating are listed in the Area Report (Appendix H). These values have been used to determine if any equipment is overstressed as a result of the inclusion of Phase II interconnections and corresponding Network Upgrades, if any.

As discussed in Section B.5.1 of the Area Report, short-circuit duty at Barre 220 kV was found to exceed the maximum nameplate ratings of all existing 220 kV breakers. Physical upgrades would necessitate replacement of all circuit breakers with a currently non-SCE standard higher rated 220 kV breaker which will necessitate in excess of $70 million and require over 48 months to implement. Because the need is currently viewed as temporary in nature and is impacted by timing of the ultimate disposition of the existing OTC units, the recommended mitigation involves implementing an operating procedure which would restrict the number of generation units that can operate (i.e., “spin”) to ensure duties at Barre 220 kV are maintained within the maximum Barre SCD ratings of 63 kA. Such restrictions may impact operations of queued projects which provide significant short-circuit duty contribution to the Barre 220 kV bus. If the queued ahead Project that triggered the need for 220 kV breaker mitigation as part of QC7 Phase II subsequently withdrawals, the operational restriction would require further evaluation to determine if the QC9 Phase I projects still trigger the need for breaker replacements.

Additionally, the QC7 Phase II studies identified a number of 66 kV circuit breakers on the Barre AB and C Sections that required upgrade under an assumption that the Barre 66 kV sectionalizing bus breakers were closed (during loss of an A-Bank) with the existing Barre Peaker in-service and operational. As part of the analysis, an additional review was performed which evaluated the potential use of an operating scheme and/or procedure to disconnect the Project anytime the Barre 66 kV sectionalizing bus breakers are closed in order to reduce SCD at Barre 66 kV. QC9 Projects will also need to be disconnected to reduce SCD under closure of sectionalizing circuit breakers.

Currently there is an existing project to replace the identified overstressed 66 kV circuit breakers on the Barre AB and C Sections. Following completion of the circuit breaker upgrade, further evaluation will be required to determine if this project would no longer be required to participate in any operating scheme and/or procedure that would disconnect the Project.
following closure of the Barre 66 kV sectionalizing bus breakers. The current completion date for this upgrade is 12/31/2019.

The responsibility to finance short-circuit related Reliability Network Upgrades identified through a Group Study shall be assigned to all projects in that Group Study pro-rata on the basis of SCD contribution of each Generating Facility.

The QC9 Phase II breaker evaluation did not identify any additional overstressed circuit breakers triggered with the inclusion of the projects in QC9 Phase II. Please refer to the QC9 Phase II Area Report for additional details.

2. Affected Systems
The SCD incremental increase to neighboring utilities due to the addition of all QC9 Phase II projects are provided in the Area Report (Section H.2). The specific SCD contribution from WDT1401 is provided in the table below.

<table>
<thead>
<tr>
<th>Short-Circuit Duty Evaluation of Adjacent Facilities Impacted by WDT1401</th>
</tr>
</thead>
<tbody>
<tr>
<td><img src="image-url" alt="Table Image" /></td>
</tr>
</tbody>
</table>

3. Distribution Provider Ground Grid Duty Concerns
The short-circuit studies flagged SCE-owned substations beyond the Project Point of Interconnection with ground grid duty concerns that necessitate a ground grid study. The Project’s contribution to Apollo, Bolsa, and Team 66 kV Substations were found to be significant and will require the project to be responsible for the cost of performing ground grid studies at these locations.

H. DELIVERABILITY ASSESSMENT RESULTS
1. On Peak Deliverability Assessment
   The Project does not contribute to any deliverability constraint.

2. Off- Peak Deliverability Assessment
   The Project does not contribute to any deliverability constraint.

3. Required Mitigations
   No Delivery Network Upgrades are required.
I. INTERCONNECTION FACILITIES, NETWORK UPGRADES, AND DISTRIBUTION UPGRADES

Please see Attachment 1 for the Distribution Provider’s Interconnection Facilities (IF’s), Reliability Network Upgrades (RNU’s), Delivery Network Upgrades7 (DNU’s), and Distribution Upgrades (DU’s) allocated to the Project. Please note that SCE will not “reserve” the identified IFs for the proposed Point of Interconnection. The identified scope/facilities will be allocated to the Project upon the successful execution of the GIA and SCE has completed the detailed design and engineering of the facilities according to tariff timelines.

J. COST AND CONSTRUCTION DURATION ESTIMATE

1. Cost Estimate

   The Project’s estimated interconnection costs, adjusted for inflation and provided in 'constant' 2017 dollars, are provided in Attachment 2 and the Project’s allocated cost for shared network upgrades are provided in Attachment 3. The costs will be utilized in developing the GIA. However, should there be a delay in executing the GIA beyond 2018, a new adjustment for inflation will be required and inserted into the GIA.

2. Construction Duration Estimate

   The construction duration for the identified facilities is as follows:

   a. Distribution Provider’s Interconnection Facilities – 27 months

      These facilities involve non-network facilities located within SCE’s Bolsa 66 kV Substation and at the IC’s Project that are necessary to complete physical interconnection of the Project and ensure adequate line protection. Please refer to Attachment 1 for details related to these facilities.

   b. Network Upgrades

      i. Plan of Service Reliability Network Upgrades

         No required Plan of Service Reliability Network Upgrades were identified in this Phase II Interconnection Study.

      ii. Short-Circuit Duty (SCD) Mitigation

         No required SCD mitigations were identified in this Phase II Interconnection Study.

   c. Voltage Support Mitigation

      No required voltage support mitigations were identified in this Phase II Interconnection Study.

   d. Distribution Upgrades - 27 months

      These facilities involve facilities located within SCE’s Bolsa 66 kV Substation that are necessary to support the physical interconnection of the Project, Ground Grid Study at Apollo, Bolsa, and Team 66 kV Substations; as well as DERMS.

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7 At the IC’s discretion, the IC or parties other than the applicable Distribution Provider pursuant to Section 10.2 of the GIP Attachment I may construct an Option (B) Generating Facility Area Delivery Network Upgrades (ADNUs) not allocated IF Deliverability. If the applicable Distribution Provider does not construct the ADNUs, the IC is not required to make the third Interconnection Financial Security posting to the Applicable Distribution Provider pursuant to Section 4.8.4.2.1 of the GIP Attachment I.
K. IN-SERVICE DATE AND COMMERCIAL OPERATION DATE ASSESSMENT

An ISD and COD assessment was performed for this project to establish the Distribution Provider’s estimate of the earliest achievable ISD based on the QC9 Phase II Interconnection Study process timelines and the time required for the Distribution Provider to complete the facilities needed to enable physical interconnection as an Interim Deliverability or Energy Only Deliverability interconnection (as applicable) for the Project. This date may be different from the Interconnection Customer’s requested ISD and will be the basis for establishing the associated milestones in the draft GIA.

Details pertaining to Full Capacity Deliverability Status and Partial Deliverability Status are provided below in Section L.

1. ISD Estimation Details

For the QC9 Phase II Interconnection Study, the estimated earliest achievable ISD is derived by the time requirements to complete the QC9 Interconnection Study Process, tender a draft GIA, negotiate and execute the GIA, and construct the necessary facilities as described below in Table A.2.

<table>
<thead>
<tr>
<th>Reference starting point</th>
<th>Days/Months</th>
<th>Issuance of Phase II Interconnection Study Report</th>
<th>11/22/2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Add:</td>
<td>30 CD</td>
<td>Phase II Results Meetings</td>
<td>12/22/2017</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Starting Point:</strong> TPD Results issued and IC response provided</td>
<td>04/02/2018</td>
</tr>
<tr>
<td>Add:</td>
<td>30 CD</td>
<td>Earliest Reasonable Tender of draft GIA</td>
<td>05/02/18</td>
</tr>
<tr>
<td>Add:</td>
<td>90 CD</td>
<td>GIA negotiation time, execution, and related activities</td>
<td>07/31/18</td>
</tr>
<tr>
<td>Add: Construction Duration</td>
<td><strong>27 months</strong></td>
<td>Construction duration outlined in the Phase II Study Report. Construction completion no earlier than date which reflects earliest ISD</td>
<td>10/31/20</td>
</tr>
<tr>
<td>Reference:</td>
<td>IC-requested ISD via Attachment B</td>
<td></td>
<td>9/15/2019</td>
</tr>
<tr>
<td>Reference:</td>
<td>IC-requested COD via Attachment B</td>
<td></td>
<td>12/31/2019</td>
</tr>
</tbody>
</table>

Difference between IC ISD and COD | 3 months

**Equals:** Earliest achievable ISD per estimated construction duration | 10/31/20
Notes on the Achievable ISD and COD calculation:

1. Assumes duration required to construct those facilities required for an Interim Deliverability Interconnection or Energy Only interconnection (as applicable) for the Project until the applicable DNUs are completed.

2. The construction durations shown represent the estimated amount of time needed to design, procure, and construct the facilities with the start date of the duration based on the effective date of the GIA; and necessarily include timely receipt of all required information and written authorizations to proceed (ATP), and timely receipt of construction payments and financial security postings and other milestones.

2. ISD Conclusion

Based on these timelines, the IC’s requested ISD of 9/15/2019 and COD of 12/31/2019 does not appear to be achievable.

The Distribution Provider can reasonably tender a draft GIA by May 2018. The draft GIA should be executed no later than early August 2018 and will include the earliest ISD and COD as identified in Table A.2.

The ISO will perform its Annual Reassessment (January - July 2018) and Transmission Plan Deliverability (TPD) Allocation⁶ (due April 2018). Any changes to the deliverability allocation resulting in changes in scope, cost, or schedule requirements that come out of ISO’s Annual Reassessment and TPD Allocation will be reflected in a 2018 Reassessment Report which will be used to revise the draft GIA (if under negotiation) or amend the GIA (if already executed). If ISO and SCE determine that the TPD Allocation Study Process outcomes do not change the scope requirements for the Project, a letter will be provided at the end of April 2018 informing the IC that there will be no changes to the allocated Network Upgrades requirements.

L. TIMING OF FULL CAPACITY DELIVERABILITY STATUS, INTERIM DELIVERABILITY STATUS, AREA CONSTRAINTS, AND OPERATIONAL INFORMATION

The Project would be granted its requested FCDS only if the Project receives TPD allocation in the forthcoming TPD Allocation Study Process. Furthermore, timing of obtaining the requested FCDS is dependent on the completion of DNUs identified below in this report, which may be updated in any subsequent annual reassessment. Until such time that these DNUs are completed and placed in-service,

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⁶The TPD Allocation Process is estimated to be completed in April 2018. The actual date may vary.
the Project may be granted Interim Deliverability Status based on annual system availability. The sections below provide a discussion of the timing of FCDS, Interim Deliverability Status, Area Constraints, and Operational Information.

1. **System Upgrades Required for Full Capacity Deliverability Status (FCDS)**
   In order to provide for FCDS, the following facilities are required in addition to the Reliability Network Upgrades described in Section 2(b) of Attachment 1:
   a. Triggered Delivery Network Upgrades – None
   b. Delivery Network Upgrades Triggered by Earlier Queued Projects – None
   c. Approved Transmission Upgrades – None
   d. Transmission Upgrades outside the CAISO Controlled Grid - None

2. **Interim Operational Deliverability Assessment for Information Only**
   The operational deliverability assessment was performed for study years 2018 ~ 2021 by modeling the Transmission and generation in service in the corresponding study year. For details of the Transmission and generation assumption, refer to Section E.3 of the Area Report. No deliverability issues were identified. Based on the study assumptions, the Project will have the deliverability status as granted by the TPD Allocation Study Process upon commercial operation.

3. **Area Constraints**
   With all approved transmission upgrades modeled, no area deliverability constraints were identified for the Project.

**M. AFFECTED SYSTEMS COORDINATION**

Please see Section H of the Area Report.

**N. ADDITIONAL STUDY ANNOTATIONS**

1. **Conceptual Plan of Service**
   The results provided in this study are based on conceptual engineering and a preliminary Plan of Service (POS) and are not sufficient for permitting of facilities. The POS is subject to change as part of detailed engineering and design.

2. The study does not include analysis related to the power output rate of change that may occur due to the following or other conditions:
   - System morning start up for solar generating facilities: That is when each morning the Generating Facility commences to generate and export electrical energy to the electric system.
   - Cloud Cover: Solar generating facilities have significant generation output variation (Variability) which can have an impact on electric system voltage profiles.

3. **IC's Technical Data**
   The study accuracy and results for the QC9 Phase II Interconnection Study was contingent upon the accuracy of the IR technical data provided by each IC during the Interconnection Study Cycle.
Any changes from the data provided as allowed by the ISO Tariff would have been submitted in Appendix B within ten (10) Business Days following the Phase I Interconnection Study Results Meeting. Any changes in the Appendix B submission that extended beyond the modifications allowed in accordance with Section 6.7.2.2 of the ISO GIDAP would have been evaluated under a Material Modification Assessment (MMA). The MMA process would have determined if such change resulted in a material impact to queued-behind generation. These change(s) would have been permitted if it was determined that there were no material impacts to queued-behind generation.

4. Study Impacts on Neighboring Utilities
Results or consequences of this Phase II Interconnection Study may require additional studies, facility additions, and/or operating procedures to address impacts to neighboring utilities and/or regional forums. For example, impacts may include but are not limited to WECC Path Ratings, short-circuit duties outside of the ISO Controlled Grid, and sub-synchronous resonance (SSR). Refer to Affected Systems Coordination Section of the Area Report for additional information.

5. Use of Distribution Provider Facilities
The IC is responsible for acquiring all property rights necessary for the IC’s Interconnection Facilities, including those required to cross the Distribution Provider’s facilities and property. This Phase II Interconnection Study does not include the method or estimated cost to the IC of Distribution Provider mitigation measures that may be required to accommodate any proposed crossing of the Distribution Provider’s facilities. The crossing of Distribution Provider property rights shall only be permitted upon written agreement between Distribution Provider and the IC at the Distribution Provider’s sole determination. Any proposed crossing of Distribution Provider property rights will require a separate study and/or evaluation, at the IC’s expense, to determine whether such use may be accommodated.

6. Distribution Provider’s Interconnection Handbook
The IC shall be required to adhere to all applicable requirements in the Distribution Provider’s Interconnection Handbook. These include, but are not limited to, all applicable protection, voltage regulation, VAR correction, harmonics, switching and tagging, and metering requirements.

7. Western Electricity Coordinating Council (WECC) Policies
The IC shall be required to adhere to all applicable WECC policies including, but not limited to, the WECC Generating Unit Model Validation Policy.

8. System Protection Coordination
Adequate Protection coordination will be required between Distribution Provider-owned protection and IC-owned protection. If adequate protection coordination cannot be achieved, then modifications to the IC-owned facilities (i.e., Generation-tie or Substation modifications) may be required to allow for ample protection coordination.

9. Standby Power and Temporary Construction Power
The Phase II Interconnection Study does not address any requirements for standby power or temporary construction power that the Project may require prior to the ISD of the Interconnection Facilities (IF’s). Should the Project require standby power or temporary construction power from the Distribution Provider prior to the ISD of the IF’s, the IC is
responsible to make appropriate arrangements with Distribution Provider to receive and pay for such retail service.

10. Licensing Cost and Estimated Time to Construct Estimate (Duration)
The estimated licensing cost and durations applied to this Project are based on the Project scope details presented in this Phase II Interconnection Study. These estimates are subject to change as the Project’s environmental and real estate elements are further defined. Upon execution of the GIA, additional evaluation including but not limited to preliminary engineering, environmental surveys, and property right checks may enable licensing cost and/or duration updates to be provided.

11. Network/Non-Network Classification of Telecommunication Facilities
   a. Non-Network (Interconnection Facilities) Telecommunications Facilities: The cost for telecommunication facilities that were identified as part of the IC’s Interconnection Facilities was based on an assumption that these facilities would be sited, licensed, and constructed by the IC. The IC will own, operate, maintain, and construct main and diverse telecommunication paths associated with the IC’s generation tie line, excluding terminal equipment at both ends. In addition, the telecommunication requirements for the RAS were assumed based on tripping of the generator’s breaker in lieu of tripping the circuit breakers and opening the IC’s gen-tie at the Distribution Provider’s substation.
   b. Network (Network Upgrades) Telecommunications Upgrades: Due to uncertainties related to telecommunication upgrades for the numerous projects in queues ahead of this Project, telecommunication upgrades for earlier queued projects without a signed GIA which upgrades have not been constructed were not considered in this study. Depending on the scope of these earlier queued projects, the cost of telecommunication upgrades identified for Phase II may be reduced. Any changes in these assumptions may affect the cost and schedule for the identified telecommunication upgrades.

12. Ground Grid Analysis
   A detailed ground grid analysis will be required as part of the detailed engineering for the Project at the SCE substations whose ground grids were flagged with duty concerns.

13. SCE Technical Requirements
   The IC is advised that there may be technical requirements in addition to those that outlined above in Section C of this report that are included in the Interconnection Handbook or that will be addressed in the Project’s GIA.

14. Applicability
   This document has been prepared to identify the impact(s) of the Project on the SCE’s electric system; as well as establish the technical requirements to interconnect the Project to the Point of Interconnection that was evaluated in the final Phase II Interconnection Study for the Project. Nothing in this report is intended to supersede or establish terms/conditions specified in GIAs agreed to by the Distribution Provider, ISO, and the IC.

15. Process for Initial Synchronization Date/Trial Operation Date and COD of the Project
   The IC is reminded that the ISO has implemented a New Resource Implementation (NRI) process that ensures that a generation resource meets all requirements before Initial Synchronization
Date/Trial Operation Date and COD. The NRI uses a bucket system for deliverables from the IC that are required to be approved by the ISO. The first step of this process is to submit an “ISO Initial Contact Information Request form” at least seven (7) months in advance of the planned Initial Synchronization Date. Subsequently an NRI project number will be assigned to the Project for all future communications with the ISO. The Distribution Providers have no involvement in this NRI process except to inform the IC of this process requirement. Further information on the NRI process can be obtained from the ISO Website using the following links:
New Resource Implementation webpage:
NRI Checklist:
NRI Guide:

16. ISO Market Dispatch
This study did not evaluate any potential limitations that may be driven by the ISO market under real-time operating conditions.

17. Future Charging Restrictions
Charging restrictions not identified in this study may occur in the future if the underlying operating assumptions prove to be different from the conditions evaluated in this study.
Attachment 1:
Interconnection Facilities, Network Upgrades, and Distribution Upgrades
Please refer to separate document
Attachment 2:
Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades
Please refer to separate document
Attachment 3:
Allocation of Network Upgrades for Cost Estimates and Maximum Network
Upgrade Cost Responsibility

No Network Upgrade cost is assigned to the Project. The Project’s maximum cost responsibility for RNUs and LDNUs is zero.
Attachment 4:
Distribution Provider’s Interconnection Handbook
Preliminary Protection Requirements for Interconnection Facilities are outlined in the Distribution Provider’s Interconnection Handbook at the following link:

Attachment 5:
Short-Circuit Duty Calculation Study Results
Please refer to the Appendix H of the Area Report
Attachment 7:
Not Used
Attachment 8:
Subtransmission Assessment Report
Please refer to separate document